# Cost and carbon emissions of coal and combined cycle power plants in India: Implications for costs of climate mitigation projects in a nascent market

Jayant Sathaye and Amol Phadke
Energy Analysis Department
Environmental Energy Technologies Division
Lawrence Berkeley National Laboratory
Berkeley, CA 94720 USA

2004

## Abstract

The Third IPCC Assessment estimated that the near-term cost of reducing carbon emissions would decline with global trading. This decline is based on the assumption that costs of reducing emissions are generally lower in the developing countries than elsewhere. In this paper, we test this hypothesis by estimating the cost of reducing emissions through the use of combined cycle units in place of coal power plants in India. Using data from power plants proposed by independent power producers, we estimate the cost of carbon reduction to be $167 per t C. Capital, fuel and other costs are all higher for combined cycles units in India than in the US, while they are comparable for the technologically mature coal plants in the two countries. Cost of carbon reduction in India and the US match at $81 per t C at a low LNG-equivalent oil price of $16 per barrel, and a high natural gas price of $4.5 per million Btu that prevailed in 2001 in the US. As the combined cycle technology matures the cost differential may narrow in the future to as low as $7 per t C.


**Key words:** Coal, combined cycle, liquefied natural gas (LNG), cost of reducing carbon emissions, India, US

## 1. Introduction

The Intergovernmental Panel on Climate Change (IPCC) assessed literature on the near-term and long-term costs of reducing carbon emissions in its Third Assessment Report (Watson et al., 2001). The near-term (up to 2010) costs of reducing emissions have been estimated to be much lower when developing countries are included in the mix of countries that would participate in the reduction of carbon emissions. Watson et al., 2001, report that without including trading of carbon emissions across countries, the costs range from $20 to $600 per t C, and with the inclusion of global trading they decline to between $5 to $125 per t C. Part of the reason for this decline is that the models of the global economy generally assume lower costs for the same mitigation options in the developing world compared to those elsewhere. For the electric power sector, Sims, Rogner, and Gregory (2003) report on the costs of reducing carbon emissions from coal power plants (pulverized fuel with flue gas desulfurization) and combined cycle gas turbine (CCGT) units. They estimate the cost for industrialized (Annex I) countries to be between $0 and $156 per t C avoided and for developing (non-Annex I) countries to be between $0 and $17 per t C avoided. How correct is this assertion about the costs being lower in the developing countries?

For the Indian electric power sector, combined cycle gas turbine plants are seen as a potential alternative to coal-fired power plants, among other options, for reducing carbon emissions (Kroeze, et al., 2004)[1]. Where inexpensive natural gas is available, combined cycle units can serve as a viable cost-effective alternative. In India, there has been a significant interest on part of private power generators, and more recently, parastatal corporations, to build combined cycle units as an alternative to coal-fired generation. In this paper, we examine the costs and emissions of proposed coal and natural gas-fired combined cycle power plants in India. Cost components are then compared with those for the same technologies in the US and other OECD countries. India has modest reserves of natural gas, although recent finds off the east coast of India may change this situation.

[1] Kroeze et al. (2004) report that the use of natural gas in place of coal power plants reduces India's 2020 GHG emissions by 14% compared to the BAU scenario. While there is some debate about whether coal and combined cycle units are perfect substitutes, in India's electricity deficit scenario, the two options have been considered as suitable alternatives for electricity generation.

We assume imported liquefied natural gas (LNG) to be the likely fuel of choice until it is clear that these reserves are economically attractive enough to be exploited for the supply of natural gas for electricity generation.

The cost of power generation is influenced by the capital cost of power plants and associated equipment, operation and maintenance, and fuel. In this paper, we analyze the sensitivity of the total cost of electricity generation to changes in each of these components. We also analyze the changes in costs between a nascent and mature market. Our analysis shows that contrary to the general assumption of lower costs of carbon reduction in developing countries, the cost of carbon emissions reduction from fuel switching in the electric power sector is higher in India and other developing countries compared to that in the US, and that each major component of the cost is likewise higher in India.

We begin in Section 2 by explaining our methodology for estimating the cost of electricity generation and carbon emissions reduction. In Section 3, we describe the sources that were used to obtain data on power generation costs and carbon emissions. Section 4 discusses the data and assumptions, and Section 5 the results of the calculations, including an analysis of their sensitivity to key input factors. In Section 6, we compare the cost of each factor in India and the US, and discuss the results of our analysis in Section 7. We summarize the key findings and present our conclusions in Section 8.

## 2. Methodology

In order to estimate the cost of carbon emissions reduction in India as a result of a shift from coal to combined cycle power generation, we analyze proposed power projects, because they best represent costs and emissions of future power plants. The cost of proposed projects is compared with that of existing projects for one state in India to illustrate the changes in costs and generation efficiency over time. The cost of reduced carbon emissions is calculated using the following expression:

*Cost of reduced carbon emissions =*

*(Cost of electricity generation from combined-cycle power plants – Cost of electricity generation from coal plants) /*

*(Carbon emissions from coal power plants – carbon emissions from combined cycle power plants)*

The above expression requires the estimation of two factors, the cost of electricity generation and associated carbon emissions. The methods for calculating these two factors are described below.

### *2.1 Estimation of the cost of electricity generation*

The cost of electricity generation from power plants may be divided into fixed and variable costs. Fixed costs are mainly capital costs and fixed operation and maintenance costs. Variable costs include fuel and variable operation and maintenance costs. The estimation of fixed costs per unit of electricity generation requires estimation of factors such as the life of the power plant, plant load factor (PLF), and discount rate. That of variable costs requires estimation of factors like fuel cost, heat rate, and fuel heat content, and the discount rate.

Table 1 below shows the steps for calculating the cost of electricity generation. The last column of this table describes the formula used to calculate a specific factor. For example, the annualized capital cost (row E) = Capital cost (row A) * Capital recovery factor  (row D).

Table 1: Steps for Calculating the Annualized Cost of Electricity Generation

| | Parameter | Unit | Formula |
|---|---|---|---|
| A | Capital Cost | $/ kW | |
| B | Life of the Power Plant | Years | |
| C | Discount Rate | Fraction | |
| D | Capital Recovery Factor | Fraction | C/(1-(1+C)^(-B)) |
| E | Annualized Capital Cost | $/kW/Year | A*D |
| F | Plant Load Factor | Fraction | |
| G | Auxiliary Consumption | Fraction | |
| H | Units Generated | kWh/kW/Year | 8670*F/(1+G) |
| I | Fixed Capital Cost | $/kWh | E/H |
| K | Fixed Operation & Maintenance Cost | $/kW | |
| L | Fixed Operation & Maintenance Cost per Unit | $/kWh | K/H |
| M | Total Fixed Costs per Unit | $/kWh | I+L |
| N | Fuel Cost | $/Kg | |
| O | Heating Value | KJ/Kg | |
| P | Heat Rate | KJ/kWh | |
| Q | Fuel Cost per Unit | $/kWh | N*P/O |
| R | O&M cost per Unit | $/kWh | |
| S | Total variable Cost | $/kWh | Q+R |
| T | Total Cost | $/kWh | S+M |

*2.2 Estimation of carbon emissions from electricity generation.*

Carbon dioxide emissions per unit of electricity generated depend on the characteristics of the fuel and power plant. Characteristics of the fuel include the energy and carbon content of the fuel, and that of the power plant include its heat rate, i.e., the amount of energy required to produce one unit of electricity, and the PLF. Carbon dioxide emissions produced are thus calculated using the following expression

*CO2 emissions per unit of electricity generated (kg C/kWh) =*
*(Carbon content of the fuel (kg C / kg of fuel) / Heat value of the fuel (GJ / kg of fuel)) * heat rate of the power plant (GJ / kWh)*

## 3. Data and Sources

In order to estimate the cost and carbon emissions per unit of electricity generated we collected data for the items noted in Table 1, and the carbon content of the two fuels. For the data on proposed power plants, we relied on power purchase agreements (PPAs) that are prepared and filed by prospective electricity generators to the regulatory commissions in order to seek approval for power plant siting and other government requirements. Data collected on existing power plants for one state, Maharashtra, are described separately. The sources of data are described below in some detail since these form the basis for our calculations, and for the comparisons with the cost of carbon emissions reductions in other countries.

### *3.1 Data on Proposed Power Plants*

Regulatory structure: In 1996, the Indian government laid out a common minimum action plan for power. It contained many elements, which were later implemented by the government, such as the establishment of state and central electricity regulatory commissions, the rationalization of retail tariffs, private sector participation in distribution, autonomy to the state electricity boards, improvement in their management practices and physical parameters of power plants, and the encouragement of cogeneration and captive power plants.

The Government of India initiated a major policy in 1998 to make the generation and supply of electricity commercially viable. It issued the Electricity Regulatory Commissions Ordinance (ERCO) 1998 in April of that year for setting up the Central Electricity Regulatory Commission (CERC) and the State Electricity Regulatory Commissions (SERCs) for tariff rationalization and other activities. CERC sets bulk tariffs for all central generating and transmission utility companies and decides on issues concerning inter-state exchange of electricity. A SERC has the authority to set tariffs for all types of electricity customers in its state.

The power projects proposed after the establishment of the independent electricity regulatory commissions (ERCs) require their approval. Hence, an important source of data for such projects are the regulatory filings, which include the petitions filed by promoters of the project to obtain the approval of the regulatory commission, and the rulings issued by the regulatory commissions.

Power purchase agreements: Data on power plants proposed by private power producers is obtained largely from the power purchase agreements (PPA) between the private power producer and the state utility company[2]. PPAs are an authentic source of data on proposed power projects, since they contain all the cost and power plant performance information agreed as a contractual requirement. However, most PPAs are generally not publicly available. After sustained efforts by non-governmental organizations (NGOs), however, these documents have been made publicly available.

Central Electricity Authority's techno-economic clearances: In addition to the clearances from the ERCs, a private power plant proposed in India needs a techno-economic clearance from the Central Electricity Authority (CEA). CEA publishes data on the approved capital cost of these projects. CEA does not, however, publish details of the performance characteristics and fuel costs of the proposed projects. We use the CEA data as a cross-check on the capital cost data obtained from the PPAs and tariff filings.

Ministry of Power's guidelines for the performance of the proposed power projects: The Indian Ministry of Power (MoP) has stipulated norms of minimum power plant performance for power projects proposed by Independent Power Producers (IPPs). Power plant performance criteria that are stipulated in the PPAs between the IPPs and the state utility companies closely follow these minimum performance norms. For example, the contract between General Electric and Enron guaranteed Enron a heat rate of 1800 kcal / kWh for the Dabhol Power Project (DPC) in India .The heat rate promised by Enron to the state utility in its PPA, however, is worse at 1920 kcal /kWh. Hence contracted norms might not indicate what can be achieved by state of the art technology, but they represent minimum norms that are used for calculation of the tariffs.

We collected data on eight proposed power projects, four of which are liquefied natural gas (LNG)-based combined cycle plants of 3495 MW of total capacity, while the other four are coal plants with 6432 MW of total capacity. Out of the four combined cycle projects, three projects were proposed by private sector IPPs and one is proposed by a parastatal organization, the National Thermal Power Corporation (NTPC). Similarly out

[2] In India, a state utility company is referred to as a State Electricity Board (SEB).

of the four coal projects, the Andhra Pradesh State Electricity Board, a state utility company, proposed one project, while private power producers proposed the other three projects. Tables 2 and 3 provide detailed data on these projects.

Table 2: Proposed Combined Cycle LNG Power Plants – Data

| | **Project Name** | **Enron** | **Patalganga** | **Kayakulam** | **Gautami** |
|---|---|---|---|---|---|
| | **Ownership** | **Private** | **Private** | **Public** | **Private** |
| Capacity | MW | 2184 | 447 | 400 | 464 |
| Capital Cost | $/KW | 965 | 826 | 669 | 704 |
| O&M Cost | % of Capital Cost | 2.5 | 2.5 | 2.5 | 2.5 |
| Discount Rate | % | 14% | 14% | 14% | 14% |
| Life | Years | 30 | 30 | 30 | 30 |
| Plant Load Factor | % | 80% | 80% | 80% | 80% |
| Fixed Cost per Unit | Cents/kWh | 1.97 | 1.68 | 1.36 | 1.43 |
| Fuel Cost | $MMBtu | 4.9 | 4.9 | 4.3 | 4.9 |
| Heat Rate | Kcal/kWh | 1877 | 2000 | 2000 | 1850 |
| Variable Cost | Cents/kWh | 3.6 | 3.9 | 3.4 | 3.6 |
| **Total Cost** | **Cents/kWh** | **5.7** | **5.6** | **4.8** | **5.1** |
| **Emissions** | **Kg C/kWh** | **0.120** | **0.128** | **0.128** | **0.118** |

Table 3: Proposed Coal Power Plants – Data

| | **Project Name** | **Bhadravati** | **Hirma** | **Rayalaseema TPP** | **Rama-gundum** |
|---|---|---|---|---|---|
| | **Ownership** | **Private** | **Private** | **Public** | **Private** |
| Capacity | MW | 993 | 4320 | 420 | 510 |
| Capital Cost | $/kW | 1328 | 967 | 1158 | 954 |
| O&M Cost | % of Capital Cost | 2.5 | 2.5 | 2.5 | 2.5 |
| Discount Rate | % | 14 | 14 | 14 | `14 |
| Life | Years | 30 | 30 | 30 | 30 |
| Plant Load Factor | % | 80% | 80% | 80% | 80% |
| Fixed Cost per Unit | Cents/kWh | 2.71 | 1.97 | 2.36 | 1.94 |
| Fuel Cost | $MMBtu | 1.62 | 0.72 | 2.36 | 0.72 |
| Plant Load Factor | % | 80% | 80% | 80% | 80% |
| Heat Content | Kcal/kg Coal | 3210 | 3360 | 3800 | 3500 |
| Heat Rate | Kcal/kWh | 2460 | 2460 | 2350 | 2400 |
| Fuel Cost | Cents/kWh | 1.52 | 0.88 | 2.11 | 0.65 |
| **Total Cost** | **Cents/kWh** | **4.4** | **2.7** | **4.6** | **2.7** |
| **Emissions** | **Kg C/kWh** | **0.266** | **0.266** | **0.254** | **0.259** |

### *3.2 Data on existing power plants*

Data on existing power plants (seven coal plants and one combined cycle plant) was obtained from the Maharashtra State Electricity Board's (MSEB) tariff filings before the

Maharashtra Electricity Regulatory Commission (MERC) (Table 4). These form part of the fuel cost adjustment proposals (FOCA) of MSEB filed to MERC. Data on the capital cost of existing plants was not available, but data on depreciation charged by MSEB per year for each power plant was available. MSEB follows a straight-line depreciation method, and hence depreciation was used as a proxy for estimating the annualized fixed costs of these plants.

## 4. Database and Parameter Assumptions

In this section we describe the data and assumptions made for the calculation of the cost of electricity generation and carbon emissions for coal and combined cycle power plants. As described in Section 3, the data on proposed power plants was collected from power purchase agreements and tariff orders.

### *4.1 Capital Cost*

The proposed power projects are to be financed by domestic as well as foreign capital. PPAs and tariff filings give the Indian rupee and US dollar components of the total capital cost. We converted the rupee component of the capital cost into equivalent US dollars by using a 2002-2003 exchange rate of Rs. 47 per US $.

### *4.2 Discount Rate*

To attract private investment for electricity generation, the Ministry of Power (MOP) guarantees a substantial return on investments by IPPs. MOP guarantees a 16 % return on equity for a prescribed plant performance (PLF of 68.5%). To give incentives for better performance, MOP also gives a bonus return on equity for improved PLF. The return on equity can go as high as 30% for a PLF of 90%.

IPPs use various types of debt finance. Rupee debt is raised at a nominal interest rate of 12-14% while the US dollar debt is raised at an interest rate of 6-8%. Debt equity ratio ranges from 2 to 5. One could use the actual financing terms of every project to arrive at the effective discount rate, but this number is difficult to estimate because of complex and often unknown financing arrangements of these projects. Instead, we apply a single discount rate of 14% for all the private power plants, which is in the neighborhood of their reported discount rates, and undertake sensitivity analysis of our results with respect to the discount rates (8% to 16%). For projects proposed by the government parastatal organizations, the actual discount rate is lower because of lower profit expectations (return on equity) and access to low cost financing. Since low cost public finance and low expected return on equity always have an opportunity cost, however, we assume the same discount rate for these projects as that for the private sector projects.

*4.3 Financial costs*

Since we are interested in comparing the overall cost of electricity generation, financial items such as an accelerated depreciation charge or the difference between loan repayment period and life of the project, which are required for the calculation of tariff schedules, are not of direct relevance. Hence, we calculate the fixed cost of electricity generation by annualizing the total capital cost of the power plant using a discount rate of 14 % and assuming a 30 year lifetime[4] for the power projects.

*4.4 Plant Load Factor*

New coal plants are generally used as base load plants whereas combined cycle plants may be used as base-load or intermediate-load plants depending on the system configuration. Typical PLF used in the planning of a base load plant is 80% while that for an intermediate load plant is 65%. In India, since there is a deficitFor our analysis, since we are interested in comparing the two types of plants as substitutes, we assume the same 80% PLF for both types of plants, and then run a sensitivity analysis at the same lower PLF of 65%.

*4.5 Fuel Prices*

The cost of coal has been relatively more stable over time compared to that of natural gas or LNG. The cost of coal in the PPAs of coal plants that we examined was only indexed to Indian inflation and remained constant in real terms over the life of the project. Fuel supply contracts for LNG, however, indexed the LNG price to that of globally traded oil,

[4] Some power purchase agreements assume a life of 20 years. At the high discount rates used in the PPA rate calculations, the difference in rates between the use of 20 and 30 years life is negligible.

which varies according to the fluctuations in the oil price. For a typical import of LNG from the Middle East to India, liquefaction- transportation - re gasification activities cost about US $ 1.2 -1.5 per million Btu. The LNG price ($/million Btu) at source (without transportation and regasification) for Enron's Dabhol power project (DPC), for example, was estimated to be 2.7*JCC/18, where JCC is the $/bbl price of the Japanese Crude Cocktail. To understand the impact of fluctuations in oil price on total costs, we start with a base JCC price of $24 per barrel (referred to as oil price in this paper) and undertake a sensitivity analysis in which the oil price ranges from $18 to $32 / barrel.

### *4.6 Carbon Content of the Fuel*

The quality (heat content) of Indian coal supplied to power plants can vary considerably, even from one train load to the next, but the carbon content is almost constant. Hence, the quality of coal is not a factor in the amount of $CO_2$ emissions produced by a coal plant. The same is true for LNG. We therefore assume a constant carbon content for coal (25.8 kg C/GJ) and LNG (15.3 kg C/GJ) across power plants and over time.

## 5. Results

We present the results for a base case, which extrapolates ongoing trends in the Indian power sector. We also present the results of the sensitivity analysis with respect to three important factors (the discount rate, oil price, and the plant load factor) and estimate their influence on the cost of electricity generation.

### *5.1 Base Case*

Using the approach and steps shown in Table 1, and the data from Tables 2 and 3, we estimate the capacity-weighted cost of electricity generation from the proposed four coal and four LNG-based combined cycle power plants (Table 4). We use a discount rate of 14%, an oil price of US $ 24 / bbl, and a PLF of 80% for both coal and LNG plants for this calculation. Table 4 clearly shows that coal power plants are cheaper than LNG plants. Due to the large variation in cost of coal (Table 3), the table shows a significant variation in the total generation costs of coal power plants. In the case of combined cycle plants, Kayakulam and Gautami have significantly lower costs due to lower capital and fuel costs (Table 2).

Table 4. Base Case Results
(Discount rate: 14%, Crude oil price: $24/bbl., Coal PLF: 80%, CC PLF: 65%)

| | Proposed Capacity | Generation Cost | $CO_2$ Emissions |
|---|---|---|---|
| | MW | Cents/kWh | Kg C/kWh |
| **Coal Based** | | | |
| Bhadravati | 993 | 4.36 | 0.26 |
| Hirma | 4320 | 2.72 | 0.26 |
| Ramagundum (BPL) | 510 | 2.68 | 0.25 |
| Rayalaseema TPP | 420 | 4.62 | 0.25 |
| **Total** | **624** | **3.10 (Wtd. Avg.)** | **0.264 (Wtd. Avg.)** |
| **CCGT** | | | |
| Enron | 218 | 5.67 | 0.12 |
| Patalganga (Reliance) | 447 | 5.61 | 0.12 |
| Kayakulam | 400 | 4.81 | 0.12 |
| Guatami | 464 | 5.07 | 0.11 |
| **Total** | **349** | **5.48 (Wtd. Avg.)** | **0.122 (Wtd. Avg.)** |
| **Average Cost of Reduced Carbon Emissions = 167 $/ t C** | | | |

Table 4 (last column) shows the CO2 (in terms of C) emissions produced per kWh from the proposed power plants, and their weighted-average values. Using the weighted averages of costs and emissions, the average cost of $CO_2$ reduction was calculated to be US $ 167 /t C.

*5.2 Sensitivity Analysis*

We tested the sensitivity of the cost of electricity generation and the cost of reducing carbon emissions to changes in the values of three key parameters the discount rate, oil price, and PLF. We analyze sensitivity to oil prices ranging from US $ 16 / bbl to US $ 32 / bbl, and to discount rates ranging from 10% to 18%, and to three different sets of PLFs, 60%, 70% and 80%.

Table 5 shows the impact of the changes in these variables on the cost of conserved carbon. Changes in the discount rates and the PLF do not significantly influence the cost of conserved carbon. The CCC varies from $ 160.6 to $172.8 per t C for changes in the discount rate from 18% to 10%, and from $159.1 to $ 166.8 for changes in the plant load factor from 60% to 80%. The changes in discount rates and PLF do not have a significant influence primarily because they affect the costs of both types of power plants. On the other hand, the CCC is very sensitive to changes in the price of LNG. The CCC increases from $ 81.5 to $ 252.1 as the oil (and hence the LNG) price increases from $16 to $ 32 per barrel.

| **Table 5: Cost of Conserved Carbon -- Sensitivity Analysis** | | | | | |
|---|---|---|---|---|---|
| Oil Price | | Discount rates | | Plant Load Factor | |
| Oil Price ($/bbl) | CCC ($/t C) | Discount Rates (%) | CCC ($/t C) | PLF (%) | CCC ($/t C) |
| 32 | 252.1 | 18 | 160.6 | 80 | 166.8 |
| 28 | 209.5 | 16 | 163.8 | 70 | 163.5 |
| 24 | 166.8 | 14 | 166.8 | 60 | 159.1 |
| 20 | 124.2 | 12 | 169.8 | | |
| 16 | 81.5 | 10 | 172.8 | | |

## 6 Cost of Electricity Generation and Emissions Reduction in India and the US

In this section, we compare each component of the cost of electricity generation for the proposed combined cycle and coal plants in India to those estimated by modelers for the US. The analysis shows that both the total costs and those of each component are higher for combined cycle units in India than in the US.

### *6.1 Capital cost*

Table 6 shows that weighted average cost of coal power plants is very similar in both countries, with the India value being slightly (3%) lower. On the other hand, the cost of the proposed combined cycle India projects is 49% higher that that in the US.

Table 6: Comparison of capital cost

| Technology | India | USA |
|---|---|---|
| | Weighted Average (US $ / kW) | EPA modeling Assumption* (US $ / kW) |
| Pulverized Coal | 1036 | 1,071 |
| CCGT | 879 | 590 |

*Source: US EPA Data base from ICF, August 2002. The capital cost of coal projects in this data base includes the cost of Flue Gas De-sulfurization (FGD) units. Indian plants do not have such equipment. Hence to compare these plants on an equal basis, the capital cost of US coal projects reported in this table excludes the cost of FGD units. The cost of FGD units was obtained from Electric Power Research Institute's Technical Assistance Guide (EPRI, 1996).

In order to corroborate this finding about the much higher capital costs of combined cycle plants, we collected data on combined cycle plants from three sources for other plants proposed in India (Table 7). These data too show that the average cost of the combined cycle units is significantly higher than in the US.

Table 7: Capital Cost of Ongoing / Approved Power Plants in India ($/KW)

| | Source I | Source II | Source III |
|---|---|---|---|
| Avg. cost of coal power plant | 927 | 1133 | 1000 |
| Avg. cost of CCGT plant | 747 | 951 | 767 |

Source 1:Ministry of Power, list of private projects with techno-economic clearance. Data for 9,781 MW of gas-based and 16,679 MW of coal-based projects respectively (MOP 1999a).
Source 2: Prayas-Project Finance Ware 2000. Data for 11,537MW of CCGT and 23,087 MW of coal-based power projects proposed in India (Prayas-Project Finance Ware 2000).
Source 3: Fuel Map for India, CEA, 1998. (CEA1998 pp. 7).

It is worth noting that the cost of combined cycle power plants in India also depends on the institution that is proposing the project. In our data base, the cost of the Kayakulam project proposed by the National Thermal Corporation (NTPC), a parastatal entity, is US $ 669 per kW (Table 1), which is lower than for the other three projects that are proposed by private generators. It is still 13% higher, however, than the estimated costs for a US combined cycle plant.

The difference in capital costs could arise for many reasons, two of which as discussed below do not appear to be the likely causes.

Risk Premium: It is often argued that power plants in a developing country cost more because of the risk of conducting business there and due to the poor credit rating of local trading partners. In the data that we used, however, the risk premium is included in the rate of return on investment guaranteed in the PPA. In the case of IPPs in India, the return on equity (ROE) is 16% at a PLF of 68.5%, which can go as high as 30% at a PLF of 85-90%. This is a sizable return and as a result, the risk premium argument does not adequately explain the higher capital cost of the IPPs.

Interest: It is often the case that construction of power plants in developing countries take more time compared to the time taken in developed countries. This is often due to unclear and evolving regulatory processes in these countries. If the construction takes longer, the interest on capital during construction can become a significant component of the total project cost. However, in most cases, IPPs are allowed to recover the cost overrun if the construction is delayed. Hence these costs need not form a part of the approved capital cost of the project at the outset since such recovery is ex-post. Hence, longer construction time is not a satisfactory explanation of the higher capital cost in India.

Other explanations for the higher costs may be the transportation costs and tariffs on imported technologies, and undue market power exercised by private electricity generators.

We reviewed data on combined cycle plants globally in order to ascertain whether our findings of higher capital costs for combined cycle plants in India would hold broadly for other developing countries. These cost estimates are shown in Table 8. Globally, cost of CC projects in developing countries is much higher than that in the industrialized countries. The cost differential increases as one moves from North America to other OECD countries and finally to Africa.

Table 8: Capital Cost of CCGT Power Plant Projects

| Region | Total Capacity (MW) | Cost in ($/kW) |
|---|---|---|
| North America | 24,831 | 573 |
| Australia and Asia Pacific | 3,288 | 615 |
| Latin America | 16,098 | 703 |
| Western Europe | 23,003 | 750 |
| Middle East | 12,823 | 793 |
| Eastern Europe | 3,632 | 796 |
| South East Asia | 14,814 | 803 |
| Indian Subcontinent | 13,299 | 875 |
| Africa | 538 | 923 |

Source: (Prayas 2001)

*6.2.2 Fuel costs.*

Natural gas and liquefied natural gas: Combined cycle plants in the US mostly use domestically produced natural gas while those in India will mostly be based on imported

LNG. LNG is costlier than natural gas because of additional costs of liquefaction, transpiration and regasification. Allocation of domestically produced natural gas for electricity generation in India amounted to 40 million $m^3$ per day or about 39% of the total allocation in 2000. Natural gas sold in India is administratively priced with the highest price at Rs. 2850 per thousand $m^3$ or US $ 1.80 per million Btu. The fuel and related costs for the existing Uran plant are 1.66 cents / kWh or about US $ 1.4 per million Btu (Appendix). The price of a typical import of LNG from the Middle East to India at the oil equivalent price of $24 per barrel would amount to $3.6 per million Btu, and with the added cost of liquefaction- transportation - re gasification of US $ 1.2 -1.5 per MBtu, the total cost would be between $4.8 and 5.1 per MBtu. Comparable price of natural gas to US electric utility plants in 2001 and 2002 was lower at $4.49 and $3.67 per MBtu (EIA, 2003).

Coal: The cost of coal for power plants in India is greatly influenced by the cost of transporting coal. In some cases transportation costs are equivalent to the pit-head cost of coal. The average cost of coal for power plants in India is around US $1.0 per million Btu, which is quite close to the cost of coal in the US.

*6.2.3 Operation and Maintenance (O&M) costs*

The minimum norm set by India's CEA for O&M costs is 2.5% of the capital costs. For US it is 2.16 % for CCGT plants and 1.52 % for the coal plants (US EPA, 2002).

*6.2.4 Heat rates*

Table 9 shows a comparison of the heat rates of power plants proposed for India and those estimated from the EPA database for the US. As in the case of other aforementioned factors, the heat rate for coal power projects is quite similar, but that for the Indian combined cycle plants is much worse. The higher heat rates translate into lower emissions reductions and higher cost of generation from combined cycle projects in India.

Table 9: Heat rates of power plants

| | India (kcal / kWh) | USA (kcal / kWh) |
|---|---|---|
| Pulverized Coal | 2,400 | 2,353 |
| Combined Cycle (LNG) | 1,903 | 1,665 |

In summary, the capital, fuel and O&M costs and the heat rates are significantly higher in India than in the US for combined cycle power plants, while these are only slightly higher in India for the relatively mature technology of coal power plants.

## 7. Alternative Scenarios

As discussed above, the capital, fuel, and other costs of Indian coal plants are only slightly higher than comparable US plants, but the difference in all cost components is much higher for combined cycle units. It is conceivable that as technologies mature, and with increased competition and transparency in contracting, the capital costs of Indian combined cycle units will approach those in the US. Indeed, the capital costs of CCGT plants increased up to 1990/91, but have declined since then due to market developments and due to improved technical performance (Colpier and Cornland, 2003). And, if domestically produced natural gas becomes more widely available (as suggested by recent finds of natural gas off India's east coast), fuel costs could also drop to US levels or even below if these are administratively set at the same levels as those for utility gas supply today. The analysis shown below estimates the cost of reducing carbon emissions for a future market in which the combined cycle technology has reached a mature stage like coal power plants today.

### *7.1 Impact of lower capital costs of CC plants*

We estimate costs for a scenario in which the capital cost of CC projects in India is at the same level as that in North America, 590 $/ kW. As in the case of coal power plants, this may happen in a mature market, where power plant capital costs are similar across countries. For our base case oil price of $24 per barrel, the cost of reducing emissions declines by 18% from $ 167 / t C to $ 137 / t C for the equal PLF case. Table 10 shows that the costs decline by the same 18% for a higher and lower price of oil.

Table 10: Impact of lower capital costs on the cost of reduced C02 emissions from combined cycle plants in India

| Oil Price ($/bbl) | Cost of Reduced $CO_2$ Emissions ($/t C) | |
|---|---|---|
| | Current Capital Costs | US Capital Costs |
| 28 | 209 | 167 |
| 24 | 167 | 137 |
| 20 | 124 | 82 |

*7.2 Impact of using domestic natural gas*

The price at which new domestic natural gas will be available has not yet been estimated. We assume two levels of domestic natural gas price, $ 3 / million Btu and $ 3.5 / million Btu, which represent the levels which are generally discussed in India (Financial Daily, 2002). Table 11 gives the cost of reduced emissions for these levels of natural gas prices.

Table 11: Impact of using domestic natural gas instead of LNG

| Natural Gas Price ($/Million Btu) | Cost of Reduced $CO_2$ Emissions ($/t C) | |
|---|---|---|
| | Current Capital Costs | US Capital Costs |
| 3.0 | 70 | 28 |
| 3.5 | 96 | 54 |

The above analysis shows that if capital costs of combined cycle projects in India decrease to US levels, and domestic natural gas becomes available at relatively lower prices, shifting from coal to combined cycle generation will be a relatively inexpensive way of reducing CO2 emissions.

*7.3 Impact of an improved heat rate*

There is a considerable difference in the heat rates of the US and Indian combined cycle power plants (see Table 9). If the heat rate of the Indian plants were to decline in the future to the US level (by 13%), the cost of carbon reduction would decline by 27% from $167 per t C (Table 4) to $122 per t C. The percentage decline of the cost of carbon reduction is higher since the heat rate reduces fuel use and carbon emissions by 13%, but since fuel cost is only one component of the total cost it reduces costs by only 8.3%.

*7.3 Combined impact of lower capital costs, domestic natural gas and an improved heat rate*

The combined impact of a lower capital cost, the use of domestic natural gas and an improved heat rate would be to lower the cost of reduced $CO_2$ emissions to levels below those discussed above for each individual impact. The cost with these three changes declines drastically to only $7 / t C.

*7.4 Cost of reducing carbon emissions in the US*

We estimated the cost of reducing carbon emissions for a shift from coal to combined cycle power plants in the US. We use the US EPA data on proposed power plants in the US to undertake this calculation (US EPA/ ICF, 2002).

After adding the cost of flue gas desulfurization (FGD) units (20%) to the capital cost of coal based plants (FGD units are required on coal based power plants in the US), the cost of electricity generated from combined cycle power plants is marginally higher than that from coal plants at a natural gas price of $2.7 per Mn Btu, and is about 0.7 cents/kWh and 1.2 cents/kWh higher using the natural gas price of $3.7 and $4.5 per Mn Btu which prevailed in 2002 and 2001 respectively.[6] The higher generation cost translates into a corresponding cost of carbon emissions reduction of $ 1, $ 44 and $ 81 per t C at the three natural gas prices. Clearly, the price of natural gas significantly influences the cost of carbon emissions reduction, but these US costs of carbon emissions reduction are lower than those estimated for India (see Table 5).

## 8. Summary and Conclusions

Climate change mitigation models of the global economy show that the cost of emissions reduction decline with global trading of emissions, and costs have been estimated to be lower for reducing carbon emissions by the use of CCGT in place of coal power plants in

[6] At a PLF of 80%, a discount rate of 5%, and a 30 year life time.

the developing countries. In part these results is based on the oft- used assumption that costs of emissions reduction are likely to be lower in the developing nations than in the industrialized countries. In this paper, we test this hypothesis by examining the cost of emissions reduction in India and the US for combined cycle plants compared with coal power plants. Our analysis shows the following:

1. The cost of electricity that will be generated by proposed combined cycle power plants that use LNG is about 5.5 cents/kWh in India, which is higher than the comparable cost of 3.1 cents / kWh for electricity from proposed coal-fired units (Table 4).
2. For a base case scenario of $24 per barrel of oil, 14% rate of discount, and a 80% plant load factor (PLF) the cost of reducing CO2 emissions is estimated to be $ 186 / t C. The cost of CO2 emissions reduction is sensitive to changes in oil prices but not to changes in the other two parameters, and ranges from $ 81 to $ 252 / t C for oil prices from $16 to $32 per barrel (Table 5).
3. The high cost of electricity from combined cycle power generation is due to higher capital, fuel, and O&M costs in India compared to those for combined cycle plants in the US. The higher fuel costs are explained by the higher costs of importing LNG into India. However, the higher capital cost of combined cycle power projects cannot be explained by physical and financial factors, and may be due to the transportation costs of, and tariffs on, imported equipment, and market power that a limited number of developers and operators are able to exercise. If the US capital cost, heat rate and natural gas price were to prevail in India, say in a mature power market, the cost of carbon reduction would decrease to only $7 per t C.
4. The cost of coal-fired generation is comparable in the US and India. Hence the cost of reduced carbon emissions from shifting from coal power plants to combined cycle plants is higher in India compared to that in the US. At a low oil, and hence LNG, price of $16 per barrel the cost of reducing carbon emissions in India matches that at the high 2001 US natural gas price of $4.5 per million Btu.

5. While our analysis has focused on data for India, the conclusions may be extended to other countries. The capital cost of combined cycle units globally is reportedly higher in developing countries than in industrialized ones, and this may translate into higher generation costs depending on whether the natural gas is indigenously available or has to be imported.
6. Finally, a key conclusion of the above analysis is that to the extent project-based activities, e.g., under CDM, rely on new technologies to generate carbon reductions; their incremental costs may be higher in developing countries, since new technology costs are often lower in the industrialized countries in a nascent market.

**Acknowledgements**: The authors wish to express their sincere thanks to Girish Sant and Shantanu Dixit, Prayas, India, for their contributions to the collection of data on proposed and existing power plants in India, and Eric Smith and Michael Shelby, US EPA for supporting this study and making data available for the US electric power sector.

## References

Central Electricity Authority (CEA) (1997) " Fourth National Power Plan 1997-2012" CEA, Government Of India (GOI): New Delhi, India.

Colpier U. and Cornland D. 2003. The economics of the combined cycle gas turbine – an experience curve analysis. *Energy Policy*. 30:309-316

ICF Consulting 2002. Performance and Unit Cost Assumptions for Potential (New) Capacity in EPA Base Case 2000

Energy Information Administration, 2003. "Electric Power Monthly" August

Electric Power Research Institute (EPRI) (1996), "Technical Assistance Guide (TAG)" EPRI California.

Financial Daily (2002) " Reliance gas find a morale booster: Naik "The HINDU group of publications http://www.blonnet.com/2002/11/09/stories/2002110902650500.htm , accessed 12th August, 2003 2:56 pm

Kroeze C., Vlablom J., Gupta J., Boudri C., and Blok K. 2004. The power sector in China and India: Greenhouse gas emissions reduction potential and scenarios for 1990-2020. *Energy Policy,* 32:55-76.

Maharashtra State Electricity Board (MSEB) (2000) "Tariff Revision Proposal submitted to Maharashtra Electricity Regulatory Commission (MERC)". MSEB: Mumbai, India

Ministry of Power (MOP) (1996) "Tariff Notification for Generating Companies.„ MOP Web-site http://powermin.nic.in/nrg47.htm , New Delhi, India

MOP (1999a) "Private Projects having Techno-economic Clearance.„ MOP Web-site www.powermin.nic.in/nrg.72

MOP (1999b) "Private Projects under Construction.„ MOP Web- site www.powermin.nic.in/nrg75.htm, New Delhi, India

Ministry of Power (1999) "Private Projects having Techno-economic Cclearance.„ MOP Website www.powermin.nic.in/nrg.72

Prayas, (2001) *Privatization or Democratization The Key to the Crises in the Electricity Sector - The Case of Maharashtra*. *Booklet*, http://www.prayaspune.org/energy/eng_pub_sel.htm, accessed 02/02/03.

Prayas -- Project Finance Ware (2000) Database search and analysis conducted by Prayas based on Project Ware data provided by the World Resources Institute. Project Finance Ware is a database product of Capital Data Limited, United Kingdom, 2000.

Sims R., Rogner H., and Gregory K. 2003. Carbon emissions and mitigation cost comparisons between fossil fuel, nuclear, and renewable energy sources for electricity generation. *Energy Policy*. 31:1315-1326

Watson R.T., Albritton D., Barker T., Bashmakov I., Canziani O., Christ R., Cubasch U., Davidson O., Gitay H., Griggs D., Houghton J., House J., Kundzewicz Z., Lal M., Leary N., Magadza C., McCarthy J., Mitchell J., Moreira J., Munasinghe M., Noble I., Pachauri R., Pittock B., Prather M., Richels R., Robinson J., Sathaye J., Schneider S., Scholes R., Stocker T., Sundararaman N., Swart R., Taniguchi T., and Zhou D. 2001. *Climate Change 2001: Synthesis Report.* A Report of the Intergovernmental Panel on Climate Change. Cambridge University Press, pp. 397.

**Sources for data on proposed power projects**

Bhadravati
MSEB & Central India Power Company (1998 )"The Power Purchase Agreement Between MSEB and Central India Power Company Ltd." Pp. 291-298

Enron
Energy Review Committee (2001) " Report of the Energy Review Committee (Part I) GOM" Authors (Madhav Godbole, Deepak Praekh , EAS Sharma , R Pachauri. Vinay Mohan Lal)

Gautami
Transmission Corporation of Andhra Pradesh Ltd. and Gautami Power Private Ltd (1997). "The Power Purchase Agreement Between Transmission Corporation of Andhra Pradesh Ltd. and Gautami Power Private Ltd." pp. 7 to 19

Hirma
CERC (2000 a)"Order of Central Electricity Regulatory Commission (No. 24/2000) CERC" CERC, New Delhi , India Pp. 1-20.

Kayakulam
CERC (2000b). "Order of Central Electricity Regulatory Commission (No. 22/99CERC, New Delhi, India Pp -1-26

Patalganga
MSEB & Reliance (1996). "The Power Purchase Agreement Between MSEB and Reliance Patalganga Power Pvt. Ltd. MSEB and Reliance" Schedule 8

Ramagundum
Andhra Pradesh State Electricity Board & BPL (1999) "Amended and Restated Power Purchase Agreement Between APSEB and BPL Power Projects (AP) Ltd. Schedule F

Rayalaseema
Andhra Pradesh Electricity Regulatory Commission (2002) "Order of APERC Order No.338/2002 Dt 29-07-2002 in OP.No.392/2001 on 2x210 MW Rayalaseema Thermal Power Projects (Stage II)" APERC India